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Industrial Boiler Low NOX Combustion Retrofit Cost Algorithm Development

Radian Corp., Research Triangle Park, NC

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ABSTRACT

This report documents the development of the low NO_x combustion cost algorithm for industrial boilers. This document describes the methods used to develop capital and annualized cost estimates. The boiler size range examined covers units with capacities ranging from 100 million Btu per hour heat input to 1300 million Btu per hour for coal firing, with oil- or gas-fired units as small as 10 million Btu/hour. All costs presented in the report are in June 1985 dollars.

The cost algorithm will become part of the Industrial Combustion Emission (ICE) model being developed for the National Acid Precipitation Assessment Program (NAPAP). The low NO_x combustion technology is one of several technologies being developed specifically for application at existing uncontrolled boilers.

Section 2.0 describes the technical approach for developing retrofit costs. Section 3.0 describes the algorithm development and presents the costing methodologies used in calculating the capital, operating and annualized costs. Section 4 lists the references utilized in this study. Appendices A and B present listings of the algorithms.

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METRIC EQUIVALENTS

Nonmetric units are used, for the most part, in this manual for the reader's convenience. Readers more familiar with metric units may use the following factors to convert to that system.

Nonmetric	Times	Yields Metric
Btu	1.06	kJ
Btu/hr	0.293	W
^{o}F	$(5/9)(^{o}F-32)$	^{o}C
ft	0.305	m
ft^2	0.0929	m^2
ft^3	0.0283	m^3
gal.	3.79	L
HP (boiler)	9.81	kW
in.	2.54	cm
lb	0.454	kg
ton	907.2	kg

1.0 INTRODUCTION

This report documents the development of low NO_x combustion retrofit cost algorithms for industrial boilers. Also included are cost algorithms for overfire air and low excess air systems. Costs are estimated for new systems as well as retrofit applications. The industrial boiler size range evaluated includes oil- and natural gas-fired units ranging from 10 to 1300 million Btu/hr* heat input capacity. Coal-fired boiler capacities evaluated range from 100 to 1300 million Btu/hr heat input. All cost estimates have been adjusted to a 1985 dollars basis.

This report summarizes the data sources and the methodology used to generate the cost algorithms. Section 2.0 describes the technical approach to acquire detailed cost data and the available sources used as the basis for the retrofit cost estimates. Section 3.0 summarizes the cost algorithm development and the boiler/burner design assumptions used to estimate costs on a per burner (or overfire air port) basis. Section 4.0 presents a list of references utilized for this study. Finally, a listing of each retrofit cost algorithm is included in Appendix A, and examples of the model input/output data are contained in Appendix B.

An effort was made to obtain actual cost data from manufacturers on new and retrofit low NO_x combustion systems applied to industrial boilers. Since the manufacturers declined to provide these data, all the costs in this report are based on published cost data and telephone contacts made with utility companies and other sources. These data are general in nature and, as such, do not address the site-specific and boiler-specific factors that can significantly affect, positively as well as negatively, NO_x reduction performance and costs of retrofit NO_x controls. The algorithms presented in this report, therefore, provide the basis for making relative comparisons of costs of control types for different fuels and boiler sizes; actual costs for a specific individual unit may vary.

*Readers more familiar with metric units may use the conversion table on page v.

2.0 TECHNICAL APPROACH

The approach taken to develop the cost and performance algorithms presented in this report was to gather available cost data on combustion modification NO_x controls. These control systems (i.e., low NO_x burners, overfire air, and low excess air controls) are integral parts of boiler design. Therefore, boiler and burner manufacturers are usually the best sources for detailed cost information. Boiler owners/operators often have only the total boiler package cost data, an unknown portion of which is attributable to the NO_x control system. Because of this, six boiler and/or burner manufacturers were contacted for detailed retrofit cost estimates.

Capital costing format forms were prepared and forwarded to these manufacturers. The American Boiler Manufacturers Association was contacted to compile these results to avoid identifying specific manufacturers when concerns were expressed about the confidentiality of the cost information. However, the cost information requested was not provided by the manufacturers for use in this study.

As a consequence, cost estimates are based upon available literature sources. Care has been taken to compare literature references to determine that the estimates are consistent before including them in preparing the cost algorithms. An assessment of the reasonableness of the scale factors used is also given when estimating costs for industrial boilers based upon cost references for larger boilers. Although the cost algorithms could be improved upon by more detailed information, they are reasonably good estimates expected to be accurate (i.e., within 30 percent).

The retrofit NO_x control cost algorithms shown in Section 3.0 were developed from cost data that had been compiled and presented in the literature. Major sources of cost data were Electric Power Research Institute (EPRI) project status reports, presented at various technical symposia. The EPRI information provided low NO_x burner costs for utility boilers using multiple burners. Most of these costs were presented as overall capital costs for a given size unit. Since industrial boilers use fewer burners, it was necessary to convert these costs to a per burner or per overfire air port

basis. Various utility survey trip reports and manufacturer contact reports were utilized to develop estimates of the number of burners as a function of boiler size.

Other cost data sources include previous Environmental Protection Agency (EPA) studies evaluating NO_x controls for utility and industrial boilers. Also, some costs from previous communications with burner manufacturers were utilized.

3.0 NOX CONTROL COST ALGORITHMS

For this analysis, nominal baseline uncontrolled NO_x emissions and retrofit NO_x control emission reduction performance estimates were used for each NO_x control technology/fuel type combination evaluated. These estimates are summarized below.

Fuel	Uncontrolled NO_x Emissions (lb/106 Btu)	NO_x Reduction, Percent			
		LEA	OFA	LNB	LNB/OFA
Coal	1.0	15	25	40	50
Residual Oil (RO)	0.45 (~0.35% N oil)	15	30	N.A.	N.A.
Natural Gas (NG) and Distillate Oil (DO)	0.25	15	30	50	N.A.

where:

LEA = low excess air control systems,
OFA = overfire air combustion ports,
LNB = low NOx burners, and
LNB/OFA = LNB plus OFA emission control systems
N.A. = Not applicable

3.1 BURNER SIZES

To estimate the number and size of burners as a function of boiler size, the available information about several coal-fired utility and industrial boilers was compiled.[1-6] These data are shown in Figure 1.

There is significant variation in the size of burners utilized by two major utility boiler manufacturers. Babcock & Wilcox generally utilizes a greater number of small burners, while Foster Wheeler manufactures the largest pulverized coal (PC) burners available.

In the industrial boiler size range, there is also a wide range of burner sizes. From Figure 1, it appears that for coal-fired industrial

boilers of capacities from 100 to 1300 million Btu/hr heat input, burner sizes generally range from about 25 to 125 million Btu/hr. Based on this information, the default values in the cost algorithms for the number of burners are listed in Table 1.

These burner arrangements are estimated to be typical for cost estimation purposes, but site-specific burner arrangements will vary. The number of overfire air (OFA) ports for single wall-fired units (as are most all industrial PC boilers in this size range) can be approximated from the burner arrangements in Figure 1. Normally, there is a single OFA port above each burner column.

These design bases allow the conversion of utility low NO_x burner and OFA total system capital costs to be converted to a per burner or per OFA port basis. Total capital costs were first converted to a per unit basis, then these unit costs were fit to a logarithmic function of unit size. Total industrial boiler system costs can be determined by multiplying these unit costs by the number of low NO_x burners or OFA ports required for that particular industrial boiler size.

3.2 CAPITAL COST ALGORITHMS

As mentioned previously, the available capital cost data were essentially presented in the literature as total system costs. Therefore, the capital cost algorithms predict total capital costs, with no component cost breakdowns.

All capital costs are presented in 1985 dollars. The Chemical Engineering capital cost indices for total plant costs were used to convert all capital costs to a common year basis. The indices used are listed on page 8.

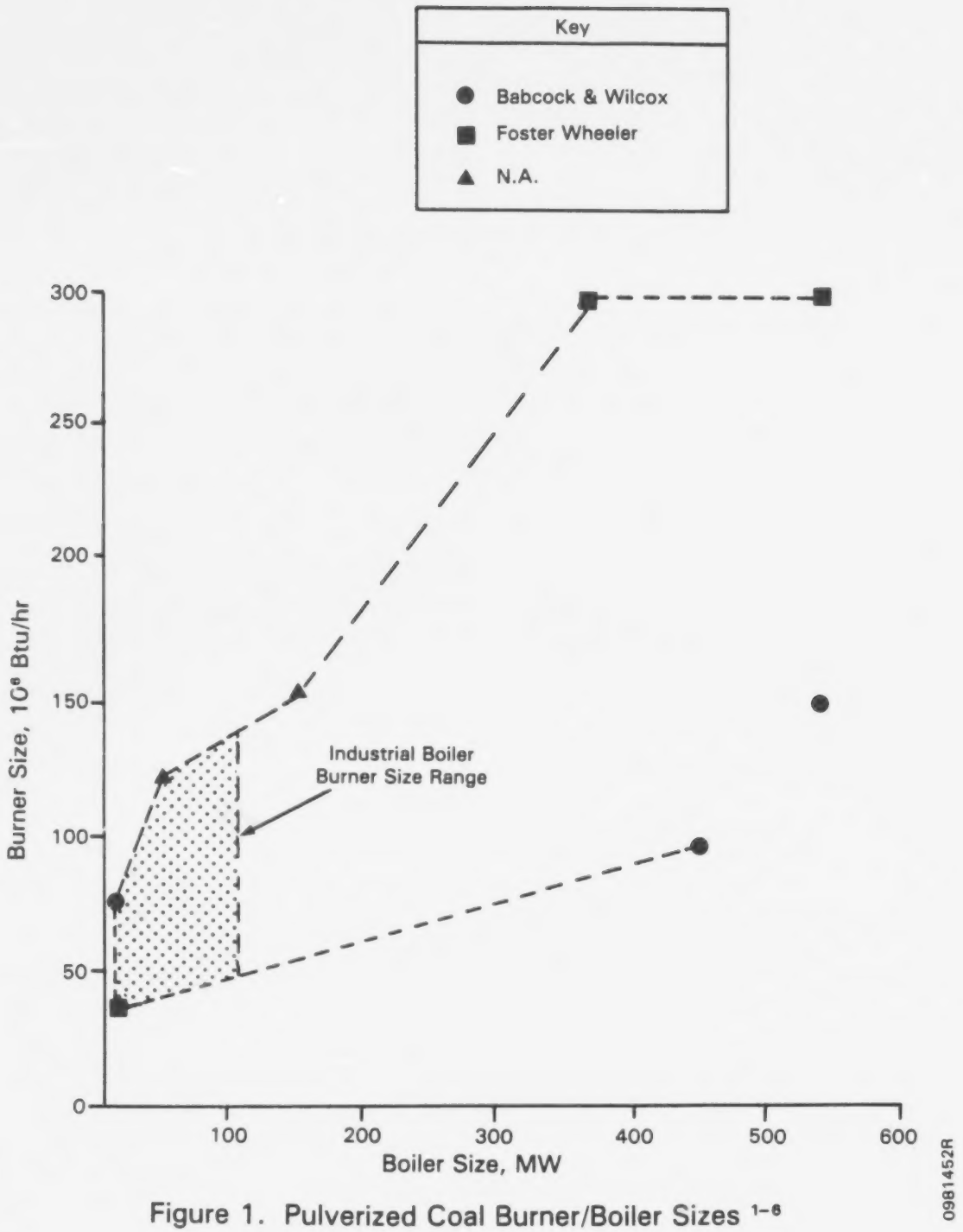

Figure 1. Pulverized Coal Burner/Boiler Sizes [1-6]

TABLE 1. COST ALGORITHM DEFAULT VALUES FOR NUMBER OF BURNERS AND OFA PORTS

Industrial Boiler Size, 10^6 Btu/hr	Potential Burner Arrangements, Row x Column	# of Burners (Default Value)		# of OFA Ports (Default Value)	
		Coal	Oil/Gas	Coal	Oil/Gas
10 - 100	1 x 1	N.A.	1	N.A.	1
100 - 250	1 x 1 or 2 x 2	4	1	2	1
250 - 500	2 x 2	4	4	2	2
500 - 750	3 x 2 or 2 x 3	6	6	3	3
750 -1000	4 x 2, 2 x 4, or 3 x 3	9	9	4	4
1000 -1300	4 x 3 or 3 x 4	12	12	4	4

N.A. = Not applicable

Year	CE Plant Cost Index
1977	204.1
1978	218.8
1979	238.7
1980	261.2
1981	297.0
1982	314.0
1983	316.9
1984	322.7
1985	325.3

3.2.1 Low NOx Burner

3.2.1.1 Pulverized Coal. The retrofit capital costs used to develop the low NO_x burner cost algorithm are summarized in Table 2.[1,7,8] The large (~500 MW) utility costs were used to estimate the costs of the largest size burner (Foster Wheeler type) available. The smaller (~200 MW) utility costs were used to estimate the smaller size burner costs.

These per burner costs are shown graphically in Figure 2. Performing a logarithmic regression of these costs as a function of burner size yields the following expression:

Total Retrofit Capital

Cost per Burner $= \$12{,}800\ (QB)^{0.43}$ (Algorithm 1)

where QB = burner heat input, 10^6 Btu/hr

The cost of a new low NO_x burner system is estimated to be approximately 65 percent of that of a retrofit system.[7] The cost of a new low NO_x burner is then as follows:

Total New Capital

Cost per Burner $= \$8{,}360\ (QB)^{0.43}$ (Algorithm 2)

TABLE 2. PULVERIZED COAL LOW NO_x BURNER RETROFIT CAPITAL COSTS ($1000)

Costs ($/kw)	Boiler Size (MW)	Total Capital Cost (year)	1985 Capital Costs	Approximate Number of Burners	Estimated Size (10^6 Btu/hr)	Capital Cost per Burner* installed (total)	Reference
5.40	540	2913 (1985)	2913	24	225	121 (161)	1, 7
9.79	200	1958 (1985)	1958	28	75	61.6 (82.0)	7
4.80	500	2400 (1982)	2480	22	225	113 (150)	1, 8

* NOTE: Total Capital Costs = Direct Installed Costs + Engineering + Construction Fees and Expenses + Startup + Performance Tests
= Direct Installed Costs X (1 + 0.1 + 0.2 + 0.02 + 0.01)
= 1.33 X Direct Installed Costs (no contingency or working capital)

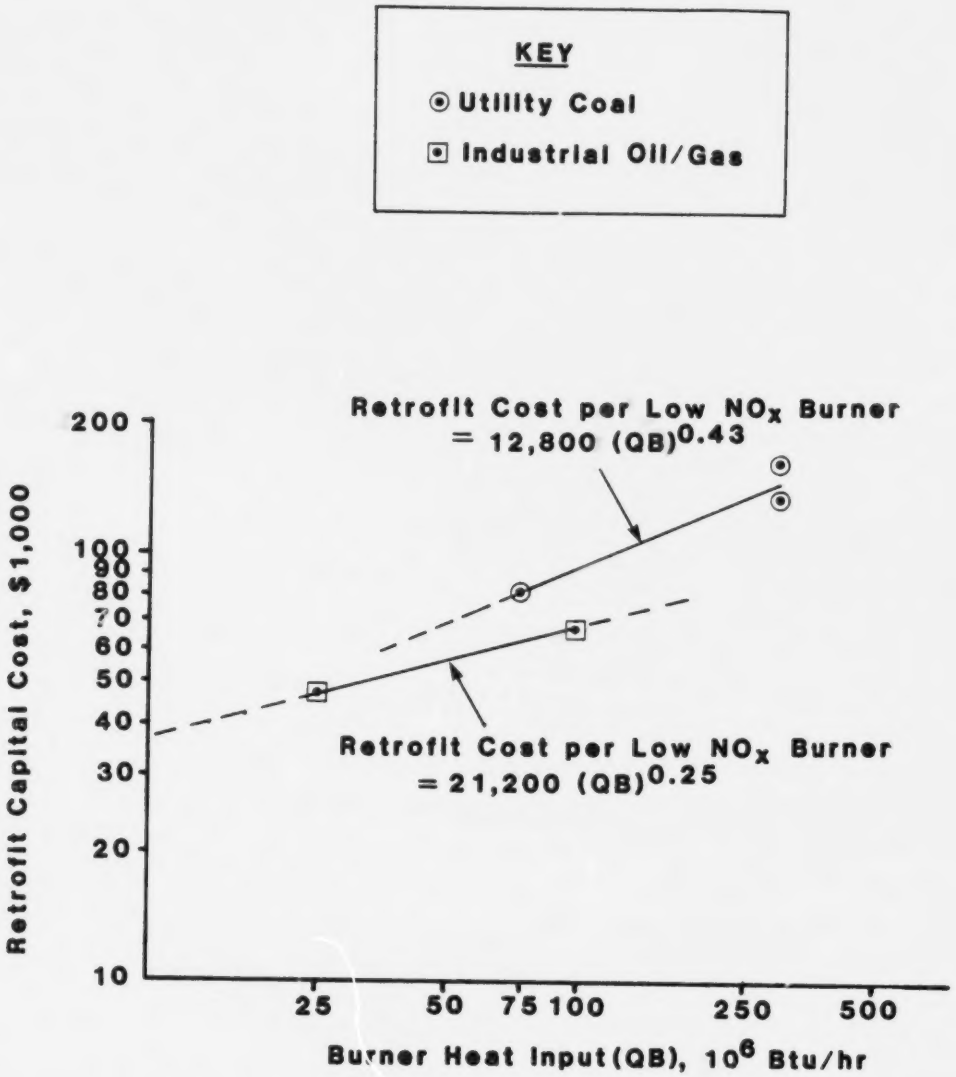

Figure 2. Retrofit Low NO_x Burner Capital Costs:
Cost per Low NO_x Burner = f (burner heat input)

3.2.1.2 Natural Gas/Distillate Oil. Also shown in Figure 2 is the retrofit capital cost equation for natural gas/distillate oil low NO_x burners applied to industrial boilers. This expression was developed from rough cost quotes from one low NO_x burner manufacturer, $18,000 for a 25 million Btu/hr burner and $25,500 for a 100 million Btu/hr burner.[9] With installation costs estimated at 30 percent of direct equipment cost and 33 percent for indirect costs, the total new capital costs are $31,300 and $44,100 respectively. These costs give the following new burner cost equation.

$$\text{Total New Capital Cost per Burner} = \$13{,}800\ (QB)^{0.25} \qquad \text{(Algorithm 3)}$$

Applying the same retrofit factor as for pulverized coal low NO_x burners (New Cost/.65) yields the retrofit capital cost equation.

$$\text{Total Retrofit Capital Cost per Burner} = \$21{,}200\ (QB)^{0.25} \qquad \text{(Algorithm 4)}$$

No costs were developed for residual oil-fired low NO_x burners as they are not presently commercially available.

3.2.1.3 Analysis of Results. The capital cost equations for low NO_x burners presented in the previous section calculate costs on a per burner basis as a function of burner heat input. To check the results of the cost equations, the case of a 1000 million Btu/hr pulverized coal boiler is examined. Based on the burner sizes shown in Figure 1 and the default values for number of burners, this boiler would require twelve 83 million Btu/hr heat input burners. The total retrofit capital costs are estimated as follows:

$$\text{Total Retrofit Capital Costs} = 12 \times 12{,}800\ (83)^{0.43}$$
$$= \$1{,}030{,}000$$

On a 100 MW boiler capacity basis, this corresponds to $10.3/KW.

Checking this total system cost against the 500 MW base costs from Reference 7 gives the following results (assuming 90% boiler thermal efficiency and 38% electrical turbine efficiency, i.e., 10,000 Btu/hr heat input = 1 KWe output).

$$\$1,030,000 = (100\ MW/500\ MW)^a\ (\$5.65/KW)(1000\ KW/MW)(500\ MW)$$

$$1,030,000 = (0.20)^a\ (2,830,000)$$

$$(0.20)^a = 0.36$$

$$a = 0.63$$

This exponent for scaling costs is close to the generally accepted 0.6 scaling factor for industrial equipment systems.[7] So, it appears that the methodology for total costs based on the per burner cost equation and the analysis of boiler and burner sizes are reasonable.

3.2.2 Overfire Air (OFA) Ports.

3.2.2.1 Pulverized Coal and Oil/Gas. The retrofit capital costs used to develop the overfire air port cost algorithm are summarized in Table 3.[10-15] The large (~500 MW) utility costs had some variation due to the different burner size/number design scheme and year of the cost estimate; however, the extreme high and low cost estimates tended to offset each other.

Industrial oil/gas OFA systems were included in the regression analysis for two reasons. First, the coal and oil/gas OFA systems are essentially identical in regard to equipment design/auxiliaries/controls. This is not necessarily true for low NO_x burners. Second, due to the above-mentioned coal OFA cost variation, costs for a broader size range were required for the regression analysis.

Cost per OFA port is shown graphically in Figure 3. Performing a logarithmic regression of these costs as a function of boiler size results in the following equation:

TABLE 3. OVERFIRE AIR (OFA) PORT RETROFIT CAPITAL COSTS ($1,000)

Boiler Size, MW	Total Capital Cost (Year)	1985 Capital Costs	No. of OFA Ports	Capital Cost per OFA Port	Reference
500	80 (1979)*	109	1*	109	10,11
500	1000 (1982)	1030	12	85.8	12,13
680	1320 (1978)	1960	8	245	14
540	335 (1978)	534	12	44.5	14
2.0	33.8 (1983)	34.7	1	34.7	15
4.0	54.1 (1983)	55.5	1	55.5	15

*Note: Costs were reported on a per OFA port basis, with 4 to 8 ports being utilized for Riley Stoker and Combusion Engineering boilers. Total costs for the entire OFA retrofit would then be 4 to 8 times the cost indicated in the table.

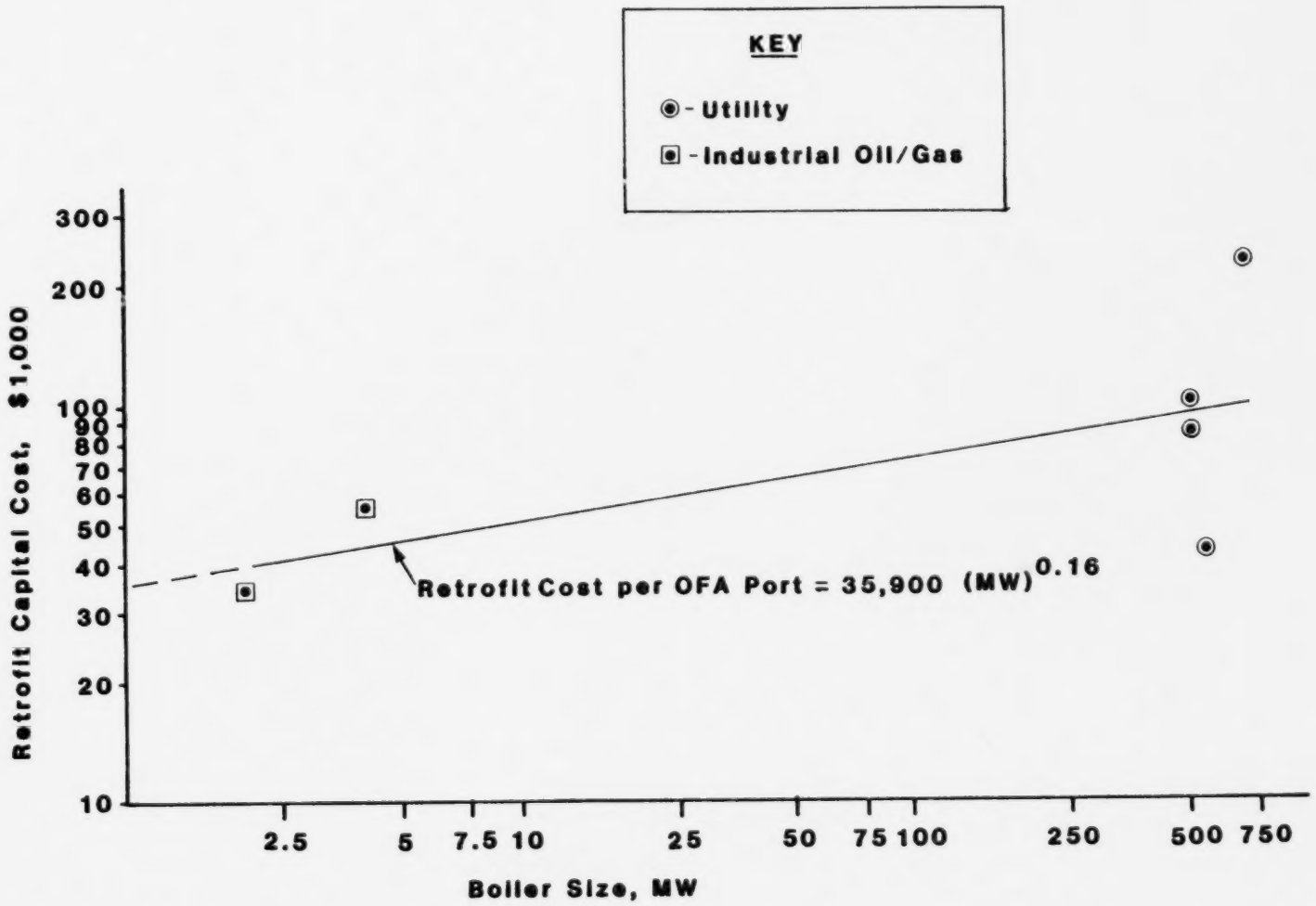

Figure 3. Retrofit OFA Port Capital Costs: Cost per OFA Port = f (boiler size)

Total Retrofit Capital
Cost per OFA Port $= \$35{,}900\ (MW)^{0.16}$

$= \$24{,}000\ (Q)^{0.16}$ (Algorithm 5)

where MW = boiler size, MW
Q = boiler heat input, 10^6 Btu/hr

The cost of a new OFA port system is estimated to be 61 percent of that of a retrofit system.[16] The cost of a new OFA port system is then as follows.

Total New Capital
Cost per OFA Port $= \$14{,}600\ (Q)^{0.16}$ (Algorithm 6)

3.2.2.2 Analysis of Results. The capital cost equations for OFA ports presented in the previous section calculate costs on a per OFA port basis. Because of the variation in utility coal data and the inclusion of small industrial oil/gas data in the regression analysis, several checks of the calculations are in order.

First, to check the variation in per OFA port costs with boiler size, a 150 million Btu/hr pulverized coal boiler case is evaluated. Based on the burner/boiler size analysis, this unit would have four burners arranged in a 2 x 2 pattern. Thus, there would be two OFA ports. The total retrofit capital costs are estimated as

Total Retrofit Capital Costs $= 2 \times 24{,}000\ (150)^{0.16}$

$= \$107{,}000$

To see how this cost scales down relative from a 500 MW utility cost, the following expression holds.

$\$107{,}000 = (15\ MW/500\ MW)^{a}\ (\$2/KW)\ (1000\ KW/MW)\ (500\ MW)$

$$107{,}000 = (.030)^{a}\ (1{,}000{,}000)$$
$$(.030)^{a} = 0.107$$
$$a = 0.64$$

This exponential size scaling factor seems in agreement with other estimates.

A further independent check of the cost equation evaluates the model industrial boiler case of a 200 million Btu/hr pulverized coal unit. A new OFA system total capital cost was estimated to be $47,000 (1978 dollars).[17] Converting this cost to 1985 dollars increases the cost to $69,900. Using the utility retrofit factor (Retrofit = New/0.61) results in an estimated retrofit cost of $115,000. For a 200 million Btu/hr pulverized coal boiler, it is estimated there would be four burners requiring two OFA ports. The total retrofit capital costs estimated by the cost algorithm equation are:

$$\text{Total Retrofit Capital Cost} = 2 \times 24{,}000\ (200)^{0.16}$$
$$= \$112{,}000.$$

This is in good agreement with the above industrial boiler cost estimate. Therefore, the OFA capital cost analysis based on a per OFA port basis and the burner size/number estimates appears to be satisfactory.

3.2.3 Low Excess Air.

Most of the available low excess air (LEA) cost data are for new industrial boiler applications. There are several reasons for this. First, a number of cost studies were performed in support of the development of New Source Performance Standards (NSPS) for industrial boilers in the late 1970's and early 1980's. Also many industrial boilers still do not operate at LEA levels. Finally, most new utility boilers have utilized LEA controls for some time, so that they are considered part of the basic new boiler system. One cost data source cited in this report estimates essentially zero capital costs associated with a new utility LEA system.[16]

The new capital costs used to develop the low excess air cost algorithm are summarized in Table 4. These costs are shown graphically in Figure 4. Performing a logarithmic regression of these costs as a function of boiler size gives the following relation:

$$\text{Total New LEA Capital Costs} = \$5{,}140\ (Q)^{0.34} \qquad \text{(Algorithm 7)}$$

These costs generally represent the use of an O_2 analyzer, automatic air/fuel flow controls, and any necessary windbox or hardware modifications.

The only retrofit LEA cost estimate obtained during this study was for a coal-fired utility application. This estimate of the capital cost of a LEA retrofit is \$0.40/KW for a front wall-fired unit.[16] Approximately 85 percent of the front wall-fired utility boiler capacity and about 92 percent of the front wall-fired units are in the 100-300 MW size range, with the balance in the 300-600 MW size range.[16] Based on this, a typical single wall-fired unit was estimated to be approximately 220 MW (0.92 x 200 + 0.08 x 450 = 220). For a 220 MW unit the LEA retrofit cost would be \$88,000 (1982), or \$91,000 in 1985 dollars. This cost is also shown in Figure 4.

To estimate the industrial boiler LEA retrofit cost, the utility retrofit cost is scaled down by using the 0.34 size scaling factor for new industrial boiler systems. This is done for two reasons. First, no retrofit and new LEA costs were available for the same size unit. Also, with a significant portion of LEA equipment costs being relatively independent of boiler size (e.g., O_2 analyzer, flow controllers, etc.), the 0.34 scaling factor seemed more reasonable than the generally utilized economy of scale factor of 0.6. This utility retrofit cost scales down to 200 million Btu/hr giving the following estimate.

$$\text{Retrofit Cost} = \$91{,}000\ (200/2200)^{0.34}$$
$$= \$40{,}300$$

The LEA new cost algorithm predicts a cost of \$31,100. This gives a retrofit/new cost ratio of 1.29, or a retrofit cost of 29% greater than that of a new system. Therefore, the LEA retrofit cost equation is:

TABLE 4. LOW EXCESS AIR (LEA) NEW CAPITAL COSTS ($1,000)

Boiler Heat Input, (10^6 Btu/hr)	Total Capital Cost (Year)	1985 Capital Cost (Year)	Reference
200	27 (1978)	40	17
100	14 (1978)	21	17
15	9 (1978)	13	17
20	16 (1983)	16	15
100	20 (1983)	21	15
200	21.2 (1978)	31.5	18

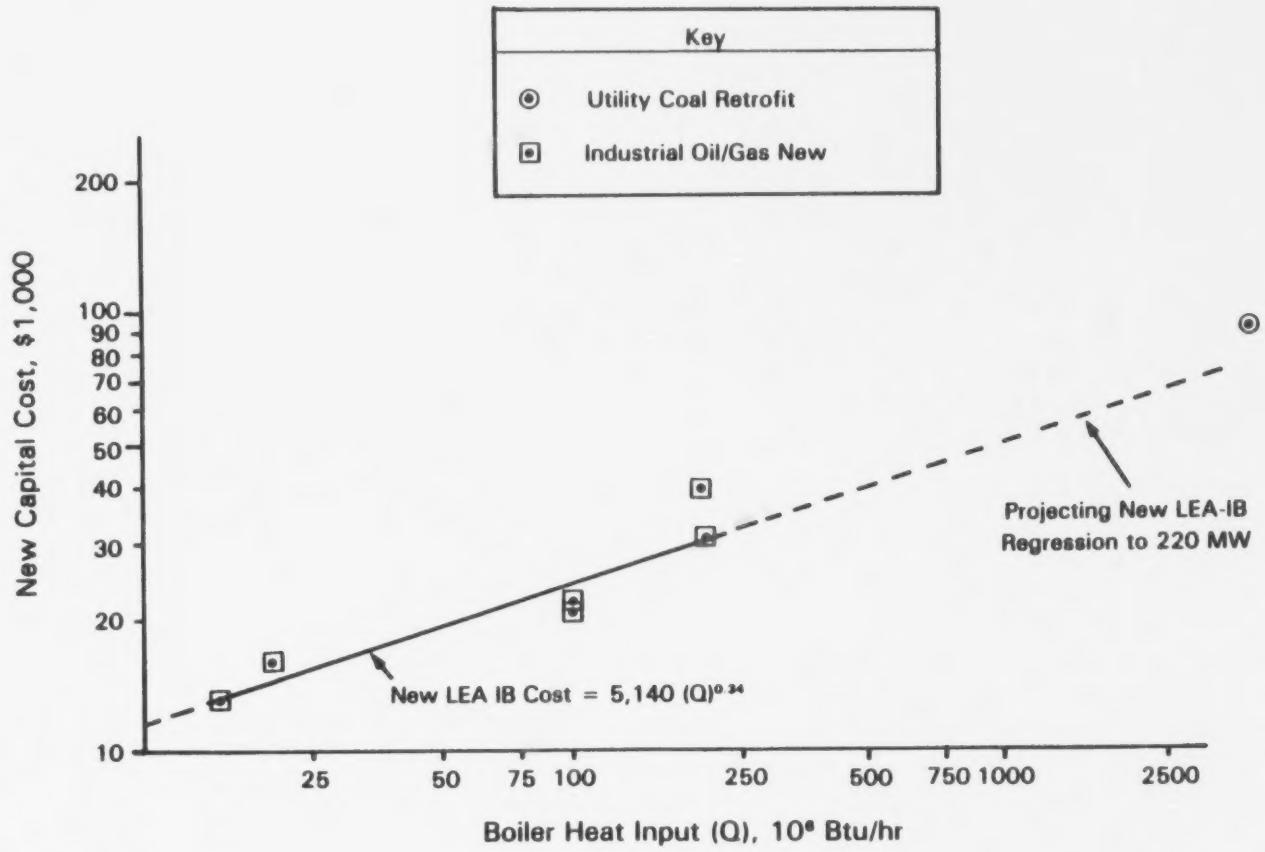

Figure 4. New LEA Capital Costs

$$\text{Total Retrofit LEA Capital Cost} = \$6{,}650\ (Q)^{0.34} \qquad \text{(Algorithm 8)}$$

3.2.4 Boiler Derate Costs.

The final capital cost impact of NO_x controls is the effect of staged combustion (both low NO_x burners and overfire air) on packaged oil- and gas-fired industrial boilers. The tight fireboxes and resulting high heat release rates of the large packaged industrial boilers limit the NO_x reduction and steam production capabilities of those systems. Therefore, a new packaged industrial boiler equipped with a low NO_x burner or overfire air will have to be built physically larger to achieve the NO_x reductions at the specified heat inputs designated in Section 3.0.

For this analysis, derate costs for industrial pulverized coal boilers were estimated to be limited to a minimal or near zero level due to the following factors, which formed the basis for the analysis:

1. LNB and OFA performance levels were reduced to less than theoretically maximum levels to accommodate less than ideal existing boiler designs for implementing retrofit LNB and OFA NO_x control systems. Although there will be exceptions, it is estimated that most of the existing industrial PC boilers retrofitted with these controls could attain the performance levels used in this analysis (i.e., 40 and 25 percent NO_x reduction for LNB and OFA respectively).
2. Industrial PC boilers are usually more economical than alternatives in the larger boiler sizes. Very few PC units have been constructed in sizes less than 250 million Btu/hour heat input. Because of their sizes, industrial PC boilers are typically field erected and have more generous firebox dimensions than would comparable gas or oil package boilers of the same heat input. In some existing PC boilers, it is recognized that the retrofit low-NO_x burner performance levels attainable may be below the above estimated value (i.e., 40 percent) due to flame length limitations. However, 40 percent reduction is considered to be attainable in the majority of

retrofits. In new units the boiler manufacturers could make adjustments in firebox dimensions at minimal cost to increase length at the expense of height or width and/or to marginally increase firebox volume. Under these conditions where there is an opportunity to optimally match the burner and boiler design to a compatible configuration, 40 percent and higher NO_x reductions should be attainable.

Thus, use of these cost algorithms should produce reasonably accurate cost estimates for installation and operation of low NO_x burner control systems, but the NO_x reductions attained after their implementation may be somewhat less than 40 percent due to limited firebox dimensions in some existing units. Conversely, reductions could exceed 40 percent in new units where boiler and burner manufacturers have produced an optimal design. OFA performance can also be affected by boiler design, but the effect is believed to be less than changes in low NO_x burner performance.

A recent study was conducted to quantify the amount of boiler derate required to accommodate staged combustion NO_x controls in new, large packaged industrial boilers. These analyses indicate that boiler derating is roughly a linear function with boiler size, ranging from no derate at 75 million Btu/hr up to about 40 percent derate at 250 million Btu/hr.[19] For new oil- and gas-fired boilers in this size range, the incremental capital cost of a larger boiler must be added to the capital costs of low NO_x burner and overfire air NO_x controls.

The total capital cost (excluding contingencies and working capital) of a new, packaged industrial oil- and gas-fired boiler is given by the following equation.[20]

$$\text{Total Packaged Boiler Capital Cost} = \$91{,}800\ (Q)^{0.62}$$

For boilers in the 75-250 million Btu/hr size range, the percent derate required for staged combustion NO_x controls can be approximated as follows:[21]

$$\% \text{ Derate} = D = 0.32\ (Q) - 24$$

Therefore, the additional incremental capital cost for derating to be added to the costs of new low NO_x burners or overfire air systems is given by the following expression:

(For oil and gas boilers where: $75 < Q < 250$) (Algorithm 9)

$$\text{Derate Capital Cost} = \$91{,}800 \ (Q(1 + D/100))^{0.62} - (Q)^{0.62}$$

For retrofit staged combustion NO_x control systems, the derate impact must be evaluated somewhat differently. An existing packaged boiler does not lend itself well to enlarging the furnace for accommodating combustion staging. Therefore, for this analysis the derating of existing packaged oil- and gas-fired industrial boilers will be addressed in terms of capacity replacement and NO_x reduction performance.

Most boilers are ordered with some amount of excess capacity to increase the reliability of maximum steam output in a multiple unit boiler house serving a manufacturing facility. Although low NO_x control systems retrofitted to existing units can impact the maximum steam output of an individual unit, when operated in a controlled emissions mode, during emergencies requiring more steam output they can be operated in a non-NO_x reduction mode to restore full rated steam output to the unit. Additionally, peak demands for steam output have been reduced by conservation programs in many industrial facilities and their steam demands are typically less than in previous years. Thus, it is unlikely that most boiler owners/operators would be compelled to install additional steam generator capacity as a consequence of low NO_x controls implemented on existing units if the impact on routine steam output were 15% or less.

Accordingly, the cost analysis is divided into two categories of boiler derates. For derates over 15%, additional costs for replacement of lost capacity are included in the anticipated cost impacts. For derates of 15% or less, these impacts are considered to have no practical effect on manufacturing output for the majority of facilities. This basis for the analysis is expected to be a sound one for the typical retrofit application, but exceptions are also expected in a minority of applications. The derate

algorithms included in this report can be used to estimate the additional impact of capacity loss.

For existing packaged natural gas-fired industrial boilers, derate costs for units rated between 75 and 250 million Btu/hour heat input are estimated for two cases.

1) Derates greater than 15%; additional costs of new boiler capacity replacement; and fixed maximum NO_x emission reduction performance (i.e., 50 percent NO_x reduction for natural gas-fired low NO_x burner applications).

2) Maximum 15% derate; no replacement costs of lost capacity; and variable NO_x emission reduction performance. For residual oil-fired packaged boilers, only the first case is evaluated because an expression relating the NO_x emissions of staged combustion systems to packaged boiler size (i.e., heat release rate) could not be developed. Derates for existing residual oil-fired packaged boilers to accommodate staged combustion retrofit are estimated as follows:

(Algorithm 10)

Residual Oil-Fired Packaged Boiler Size, 10^6 Btu/hr	% Derate
75-100	15
100-150	20
150-200	30
200-250	40

Based on these derate levels, retrofit capacity replacement costs are calculated in a similar manner as for new systems.

For natural gas-fired units, low NO_x burner performance is related to boiler size in terms of heat release rate. This expression is used to estimate the variable NO_x emission reduction performance for the maximum 15% derate/no capacity replacement case as follows:

(Algorithm 11)

- Calculate full load area heat release rate

  $HRRF = 55.4 \ln (Q) - 131$

- Calculate area heat release rate at 15 percent derate

  $HRRD = 0.85\ HRRF$

- Convert area heat release rate to volumetric heat release rate

  $VHRR = HRRD\ (0.655 - 0.000496\ Q)$

- Calculate NO_x emissions

  $NO_x = 0.0029\ VHRR - 0.0401$

- Calculate NO_x emission reduction performance

  $\%\ Reduction = (100)\ (0.25 - NO_x)/(0.25)$

where, Q = boiler heat input, 10^6 Btu/hr
$HRRF,D$ = area heat release rate, 10^3 Btu/hr-ft^2
$VHRR$ = volumetric heat release rate, 10^3 Btu/hr-ft^3

For derates greater than 15 percent with capacity replacement, these expressions are rearranged to calculate derate percentages as a function of the required NO_x emission level (e.g., 0.125 lb/10^6 Btu at the default maximum 50 percent NO_x reduction):

$$\%\ Derate = [(HRRF - HRRD) / (HRRF)]\ [100] \qquad \text{(Algorithm 12)}$$

$$HRRF = 55.4 \ln (Q) - 131$$

$$HRRD = (TLNO_x + 0.0401) / [0.0019 - (1.44)\ (106)\ (Q)]$$

where, $TLNO_x$ = target level NO_x emissions, lb/10^6 Btu
$HRRF$ = full load heat release rate, 10^3 Btu/hr ft^2
$HRRD$ = derated heat release rate, 10^3 Btu/hr ft^2

3.3 ANNUALIZED COSTS

There are essentially no detailed data available on the operating costs associated with the retrofit of NO_x controls to utility and industrial boilers. The main reason for this is that few NO_x control systems have been retrofitted to existing boilers. The cases where retrofit NO_x controls have been utilized were primarily at utilities, where individual component costs are difficult to specify, particularly for NO_x controls. These types of capital cost assessments are a primary part of the previously discussed EPRI projects.

For this study, the following assumptions were made to estimate the annual operating costs of retrofit NO_x controls.

- o No additional labor.
- o No additional maintenance.
- o No fuel penalty for low NO_x burners or OFA.
- o No fuel savings for LEA.

The total annualized costs are the sum of the annual O&M costs and the annualized capital charges. The annualized capital charges include the payoff of the capital investment (capital recovery), general and administrative costs, taxes, and insurance. Table 5 presents the methodology used to calculate the annualized capital charge components.[20] The capital recovery cost is based on the equipment life, real interest rate, and total capital cost. For this analysis a 10 percent real interest rate and a 15 year equipment life is assumed. This translates into a capital recovery factor of 13.15 percent.

3.4 SUMMARY

A number of capital cost algorithms are included in this section. Their applicability is summarized below (by algorithm number).

TABLE 5. ANNUALIZED COST COMPONENTS[20]

(1) Total Annualized Cost = Annual O&M Cost + Capital Charges

(2) Capital Charges = Capital Recovery + G&A + Taxes + Insurance

(3) Calculation of Capital Charge Components

A. Capital Recovery = Capital Recovery Factor (CRF) x Total Capital Cost

$$CRF = \frac{i\ (1 + i)^n}{(1 + 1)^n - 1}$$

i = interest rate

n = number of years of useful life of boiler or control system

Item	n	i	CRF
Boiler, control systems	15	10	0.1315

B. G&A, Taxes and Insurance = 4% of Total Capital Cost

NOTE: No interest on working capital is included in this estimate.

Fuel	Industrial Boiler Size, 10^6 Btu/hr			
	10-75	75-100	100-250	250-1300
Pulverized Coal	N.A.	N.A.	1,2,5-8	1,2,5-8
Residual Oil	5-8	5-10	5-10	5-8
Natural Gas and Distillate Oil	3-8	3-9,11,12	3-9, 11,12	3-8

One final check of the LNB retrofit methodology is made by analyzing the preliminary results of one of the aforementioned EPRI projects.[22] In that study, a major U. S. utility boiler manufacturer performed a detailed engineering and economic evaluation of several retrofit low NO_x burner case studies. The smallest unit evaluated was a 140 MW, front wall-fired pulverized coal utility boiler (equipped with 16 burners). Total capital costs were estimated at \$8.7/KW or \$1,220,000.

Using an estimated boiler heat rate of 10,000 Btu/kwh results in an estimated heat input of 1,400 x 106 Btu/hr. This boiler size capacity is slightly larger than the size range of industrial boilers evaluated in this study. However, extrapolating the values for the number of burners listed in Table 1, this unit would likely be equipped with 12-16 burners (between 4 x 3 or 3 x 4 and 4 x 4 burner arrangements).

Basing the cost estimate on 12 burners, each ~117 x 10^6 Btu/hr low NO_x burner would cost \$99,200, resulting in a total retrofit capital cost of \$1,190,000 or \$8.5/KW (Algorithm 1). Using a larger number of smaller burners results in 16 low NO_x burners of ~87.5 x 10^6 Btu/hr heat input, each costing \$87,600 resulting in a total retrofit capital cost of \$1,400,000, or \$10.0/KW.

These cost estimates based on the retrofit industrial boiler algorithms developed in this study are within -3 to +15 of the boiler manu-facturer's estimate. These costs are within the 30 percent accuracy range estimated for this methodology. Thus, is appears that the PC LNB retrofit cost methodology reasonably predicts costs developed by detailed engineering evaluations. These algorithms can be updated further when cost and performance data from full-scale, retrofit LNB demonstration projects become available.

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Appendix A

TABLE A-1. COAL EXAMPLE CASE.

INPUT DATA FOR COAL

Boiler Size (MMBtu/hr) - (C)	225
Capacity Factor (Value or 0=Default)	0
Fuel Type (Coal=1)	1
Uncontrolled NOx Emissions (lb/MMBtu)	1
Control Type (1=LEA,2=OFA,3=LNB,4=LNB/OFA)	3
Number of Burners (0=Default or Number)	0
Number of Overfire Air Ports (0=Default or Number)	0
System Type (1=New 2=Retrofit)	2
Interest Rate (Percent or 0=Default)	10
Service Life (Number of Years or 0=Default)	15

****
LOW NOx COST CALCULATIONS FOR COAL
****

DEFAULT VALUES

% NOX REDUCTION (PNR)	40
# BURNERS (B)	4
# OVERFIRE AIR PORTS (OFA)	2
UNCONTROLLED NOX EMISSIONS	1
INTEREST RATE =	10
	15
CAPACITY FACTOR =	0.6

CAPITAL COSTS CALCULATION

LEA	0
OFA	0
LNB	289616
LNB/OFA	0
CAPITAL COST=	289616

ANNUAL COSTS

CAPITAL RECOVERY FACTOR =	0.1315
ANNUALIZED COST =	49662

COST EFFECTIVENESS ($/TON)

CAPACITY FACTOR	0.6
COST EFFECTIVENESS	210

TABLE A-2. NATURAL GAS/DISTILLATE OIL EXAMPLE CASE

INPUT DATA FOR NATURAL GAS/DISTILLATE OIL

Boiler Size (MMBtu/hr) -	225
Capacity Factor (Value or 0=Default)	0
Fuel Type (1=Coal, 2=RO, 3=NG)	3
Control Type (1=LEA,2=OFA,3=LNB)	3
Number of Burners (0=Default or Number)	0
System Type (1=New 2=Retrofit)	2
Capacity Replacement (1=No, 2=Yes) For 75>=Q<250	1
Interest Rate (Percent or 0=Default)	10
Service Life (Number of Years or 0=Default)	15

****
NATURAL GAS/DISTILLATE OIL
****

I. INPUT CONTROL TYPE	3
PERCENT NOX REDUCTION (PNR)	50
UNCONTROLLED NOx	0.25
CONTROLLED NOX EMISSIONS (CNOX/MMBTU)	0.125
II. INPUT BOILER SIZE	225
INPUT # BURNERS	0
# OF BURNERS (B)	1
INPUT SYSTEM TYPE	2

III. IF LNB WHERE MMBTU<250,CALCULATE AREA HEAT RELEASE RATE (

AREA HEAT RELEASE RATE (AHRR) FOR MMBTU<250	169

FOR LNB WHERE 75>=MMBTU<250, IS THERE CAPACITY REPLACEMENT? (1

INPUT CAPACITY REPLACEMENT IF REQUIRED	1

IF THERE IS NO CAPACITY REPLACEMENT THEN:

A: IF CONTROL TYPE=1 OR MMBTU<75 OR MMBTU>250, THEN CRC=0 (

B. 75:=MMBTU<250 CASE

*AREA HEAT RELEASE (AHRR) FOR 75>=MMBTU<250 (CONDITIONAL)	144
VOLUMETRIC HEAT RELEASE RATE (VHRR)	92
CONTROLLED NOX EMISSIONS (CNOX/MMBTU)	0.22630

TABLE A-2. NATURAL GAS/DISTILLATE OIL EXAMPLE CASE (Concluded)

CAPACITY REPLACEMENT COST (CRC)	0
DERATED BOILER CAPACITY (QD=Q) - NO DERATE	
C. CT=3 AND 75>=MMBTU<250 AND CR=2	
TARGET HEAT RELEASE RATE (THRR)	0
% DERATE REQUIRED (PD)	0
DERATED BOILER CAPACITY QD (MMBTU/HR)	0
ADDITIONAL CAPACITY REQUIRED DUE TO DERATING (QA	0
CONDITIONAL CAPACITY REPLACEMENT COST (CRC/$)	0
CONDITIONAL CAPACITY REPLACEMENT COST (CRC/$)	0
ACTUAL CAPACITY REPLACEMENT COST (CRC/$)	0
V. CALCULATE COSTS (CC)	0
CONTROL TYPE=1/SYSTEM TYPE=1	0
CONTROL TYPE=1/SYSTEM TYPE=2	0
CONTROL TYPE=3/SYSTEM TYPE=1 75<=Q<250	0
CONTROL TYPE=3/SYSTEM TYPE=2 75<=Q<250	82107
CONTROL TYPE=3/SYSTEM TYPE=1 AND NOT 75<=Q<250	0
CONTROL TYPE=3/SYSTEM TYPE=2 AND NOT 75<=Q<250	0
CAPITAL COST	82107
VI. ANNUALIZED COSTS	
INPUT INTEREST RATE (%)	10
INPUT SERVICE LIFE (# YEARS)	15
CAPITAL RECOVERY FACTOR (CRF)	0.1315
ANNUAL COST (AC)	14079
VII. COST EFFECTIVENESS	
CAPACITY FACTOR	0.50
CONTROLLED NOx LEVEL	0.226
COST EFFECTIVENESS (CE) ($/TON NOX REMOVED)	229

TABLE A-3. RESIDUAL OIL EXAMPLE CASE.

INPUT DATA FOR RESIDUAL OIL

Boiler Size (MMBtu/hr) -	225
Capacity Factor (Value or 0=Default)	0
Fuel Type (1=Coal, 2=RO, 3=NG)	2
Control Type (1=LEA,2=OFA)	2
Number of Burners (0=Default or Number)	0
Number of Overfire Air Ports (0=Default or Number)	1
System Type (1=New 2=Retrofit)	2
Capacity Replacement (1=Yes, 2=No) For 75>=Q<250	1
Interest Rate (Percent or 0=Default)	10
Service Life (Number of Years or 0=Default)	15

****

LOW NOX COSTS FOR RESIDUAL OILS

****

DEFAULT VALUES

PERCENT NOX REDUCTION	30
CONTROLLED NOX EMISSIONS	0.315
UNCONTROLLED NOX EMISSIONS	0.45
OVERFIRE AIR PORTS (OFA)	1
PERCENT DERATE (PD)	40
DERATED BOILER CAPACITY (QD)	375
INTEREST RATE	10
SERVICE LIFE	15
CAPACITY FACTOR	0.55

ADDITIONAL CAPACITY REQUIRED DUE TO DERATING (QA)

NEW SYSTEM	0
RETROFIT SYSTEM	150
	150

CAPACITY REPLACEMENT COST (CRC)

SIZE >= 250	1004502

CAPITAL COSTS

LEA	0
OFA	1061592
	1061592

ANNUALIZED COST

CAPITAL RECOVERY FACTOR (CRF)	0.1315
ANNUALIZED COST	182035
COST EFFECTIVENESS	2488

Appendix B

TABLE B-1. COAL MODEL LISTING

```
A1: [W53] 'INPUT DATA
A3: [W53] 'Boiler Size (MMBtu/hr) -  (C)
B3: [W9] 225
A4: [W53] 'Capacity Factor (Value or 0=Default)
B4: [W9] 0
A5: [W53] 'Fuel Type (Coal=1)
B5: [W9] 1
A6: [W53] 'Uncontrolled NOx Emissions (lb/MMBtu)
B6: [W9] 1
A7: [W53] 'Control Type (1=LEA,2=OFA,3=LNB,4=LNB/OFA)
B7: [W9] 3
A8: [W53] 'Number of Burners (0=Default or Number)
B8: [W9] 0
A9: [W53] 'Number of Overfire Air Ports (0=Default or Number)
B9: [W9] 0
A10: [W53] 'System Type (1=New 2=Retrofit)
B10: [W9] 2
A11: [W53] 'Interest Rate (Percent or 0=Default)
B11: [W9] 10
A12: [W53] 'Service Life (Number of Years or 0=Default)
B12: [W9] 15
A15: [W53] \*
B15: [W9] \*
A16: [W53] '     LOW NOx COST CALCULATIONS FOR COAL
A17: [W53] \*
B17: [W9] \*
A19: [W53] 'DEFAULT VALUES
A20: [W53] \=
B20: [W9] \=
A21: [W53] '% NOX REDUCTION (PNR)
B21: [W9] @IF(B7=1,15,@IF(B7=2,25,@IF(B7=3,40,@IF(B7=4,50,0))))
A22: [W53] '# BURNERS (B)
B22: [W9] @IF(B8=0,@IF(B3>=100#AND#B3<500,4,@IF(B3>=500#AND#B3<750,6,@IF(B3>=750#AND#B3<1000,9,@if(b3>=1000#and#b3<1300,12,0)))),B8)
A23: [W53] '# OVERFIRE AIR PORTS (OFA)
B23: [W9] @IF(B9=0,@IF(B3>=100#AND#B3<500,2,@IF(B3>=500#AND#B3<750,3,@IF(B3>=750#AND#B3<1300,4,0))),B9)
A24: [W53] 'UNCONTROLLED NOX EMISSIONS
B24: [W9] @IF(B5=1,1,0)
A25: [W53] 'INTEREST RATE       =
B25: [W9] @IF(B11=0,10,B11)
B26: [W9] @IF(B12=0,15,B12)
A28: [W53] 'CAPACITY FACTOR      =
B28: [W9] @IF(B4=0,0.6,B4)
```

TABLE B-1. CONTINUED

```
A31: [W53] 'CAPITAL COSTS CALCULATION
A32: [W53] \=
A33: [W53] 'LEA
B33: (F0) [W9] @IF(B7=1#AND#B10=1,5140*B3^0.34,@IF(B7=1#AND#B10=2,6150*B3^0.34,0))
A34: [W53] 'OFA
B34: (F0) [W9] @IF(B7=2#AND#B10=1,14600*B23*B3^0.16,@IF(B7=2#AND#B10=2,24000*B23*B3^0.16,0))
A35: [W53] 'LNB
B35: (F0) [W9] @IF(B7=3#AND#B10=1,8360*B22*(B3/B22)^0.43,@IF(B7=3#AND#B10=2,12800*B22*(B3/B22)^0.43,0))
A36: [W53] 'LNB/OFA
B36: (F0) [W9] @IF(B7=4#AND#B10=1,14600*B23*B3^0.16+8360*B22*(B3/B22)^0.43,@IF(B7=4#AND#B10=2,24000*B23*B3^0.16+12800*B22*(B3/B22)^0.43,0))
A38: [W53] 'CAPITAL COST=
B38: (F0) [W9] @IF(B7=1,B33,@IF(B7=2,B34,@IF(B7=3,B35,@IF(B7=4,B36,0))))
A41: [W53] 'ANNUAL COSTS
A42: [W53] \=
A43: [W53] 'CAPITAL RECOVERY FACTOR   =
B43: (F4) [W9] (B25/100)*((1+B25/100)^B26)/(((1+B25/100)^B26)-1)
A44: [W53] 'ANNUALIZED COST           =
B44: (F0) [W9] (B43+0.04)*B38
A47: [W53] 'COST EFFECTIVENESS ($/TON)
A48: [W53] \=
A49: [W53] 'CAPACITY FACTOR
B49: [W9] @IF(B4=0,0.6,B4)
A51: [W53] 'COST EFFECTIVENESS
B51: (F0) [W9] (B44/(B49*8760*B3*B6*(B21/100)/2000))
```

TABLE B-2. NATURAL GAS/DISTILLATE OIL MODEL LISTING

```
A1: [W53] 'INPUT DATA FOR NATURAL GAS/DISTILLATE OIL
A3: [W53] 'Boiler Size (MMBtu/hr) -
B3: [W9] 225
A4: [W53] 'Capacity Factor (Value or 0=Default)
B4: [W9] 0
A5: [W53] 'Fuel Type (1=Coal, 2=RO, 3=NG/DO)
B5: [W9] 3
A6: [W53] 'Control Type (1=LEA,2=OFA,3=LNB)
B6: [W9] 3
A7: [W53] 'Number of Burners (0=Default or Number)
B7: [W9] 0
C7: [W53] 'Number of Overfire Air Ports (0=Default or Number)
D7: [W9] 0
A8: [W53] 'System Type (1=New 2=Retrofit)
B8: [W9] 2
A9: [W53] 'Capacity Replacement (1=No, 2=Yes)
B9: [W9] 1
A10: [W53] '  For 75>=Q<250
A11: [W53] 'Interest Rate (Percent or 0=Default)
B11: [W9] 10
A12: [W53] 'Service Life (Number of Years or 0=Default)
B12: [W9] 15
A18: [W53] \*
A19: [W53] 'NATURAL GAS/DISTILLATE OIL
A20: [W53] \*
A21: [W53] 'I.  INPUT CONTROL TYPE
B21: [W9] +B6
A23: [W53] '    PERCENT NOX REDUCTION (PNR)
B23: [W9] @IF(B6=1,15,@IF(B6=2,30,@IF(B6=3,50,0)))
A24: [W53] '    UNCONTROLLED NOx
B24: [W9] @IF(B5=3,0.25,0)
A25: [W53] '    CONTROLLED NOX EMISSIONS (CNOX/MMBTU)
B25: [W9] +B24*(100-B23)/100
A26: [W53] \-
A27: [W53] 'II. INPUT BOILER SIZE
B27: [W9] +B3
A29: [W53] '    INPUT # BURNERS
B29: [W9] +B7
```

TABLE B-2. CONTINUED

```
A31: [W53] '    # OF BURNERS (B)
B31: [W9] @IF(B7=0,@IF(B3>=10#AND#B3<250,1,@IF(B3>=250#AND#B3<500,4,@IF(B3>=500#AND#B3<750,6,@IF(B3>=750#AND#B3<1000,9,@if(b3>=1000#and#b3<1300,12,0))))),B7)
C31: [W53] '# OVERFIRE AIR PORTS (OFA)
D31: [W9] @IF(D7=0,@IF(B3>=10#AND#B3<250,1,@IF(B3>=250#AND#B3<500,2,@IF(B3>=500#AND#B3<750,3,@IF(B3>=750#AND#B3<1300,4,0)))),D7)
A33: [W53] '    INPUT SYSTEM TYPE
B33: [W9] +B8
A35: [W53] \-
A37: [W53] 'III. IF LNB WHERE MMBTU<250,CALCULATE AREA HEAT RELEASE RATE (AHRR)
A39: [W53] '    AREA HEAT RELEASE RATE (AHRR) FOR MMBTU<250
B39: (F0) [W9] @IF(B3<250,55.4*@LN(B3)-131,0)
A41: [W53] 'FOR LNB WHERE 75>=MMBTU<250, IS THERE CAPACITY REPLACEMENT? (1=YES,2=NO)
A43: [W53] '    INPUT CAPACITY REPLACEMENT IF REQUIRED
B43: (F0) [W9] +B9
A45: [W53] 'IF THERE IS NO CAPACITY REPLACEMENT THEN:
A47: [W53] '   A: IF CONTROL TYPE=1 OR MMBTU<75 OR MMBTU>250, THEN CRC=0 (SEE SECTION)
A49: [W53] '   B. 75>=MMBTU<250 CASE
A51: [W53] '      *AREA HEAT RELEASE (AHRR) FOR 75>=MMBTU<250
B51: (F0) [W9] @IF(B6=3#AND#B3>=75#AND#B3<250#AND#B9=1,839*0.85,0)
A52: [W53] '      (CONDITIONAL)
A54: [W53] '      VOLUMETRIC HEAT RELEASE RATE (VHRR)
B54: (F0) [W9] +B39*(0.655-0.000496*B3)
A56: [W53] '      CONTROLLED NOX EMISSIONS (CNOX/MMBTU)
B56: (F5) [W9] 0.0029*B54-0.0401
A58: [W53] '      CAPACITY REPLACEMENT COST (CRC)
B58: (F0) [W9] 0
A60: [W53] '      DERATED BOILER CAPACITY (QD=Q) - NO DERATE
A63: [W53] 'C.  CT=3 AND 75>=MMBTU<250 AND CR=2
A65: [W53] '    TARGET HEAT RELEASE RATE (THRR)
B65: (F0) [W9] @IF(B9=2,(B25+0.0401)/(0.0019-0.00000144*B3),0)
A67: [W53] '    % DERATE REQUIRED (PD)
B67: (F0) [W9] @IF(B9=2,(B39-B65)/(B39)*100,0)
A69: [W53] '    DERATED BOILER CAPACITY QD (MMBTU/HR)
B69: (F0) [W9] @IF(B9=2,B3/(1-(B67/100)),0)
A71: [W53] '    ADDITIONAL CAPACITY REQUIRED DUE TO DERATING (QA)
B71: (F0) [W9] @IF(B9=1,B69,@IF(B9=2,(B69-B3),0))
A73: [W53] '    CONDITIONAL CAPACITY REPLACEMENT COST (CRC/$)
B73: (F0) [W9] @IF(B9=2#AND#B71>=250,1004*(8+59.47*(B67)+7.52*(B71)),0)
A74: [W53] '    CONDITIONAL CAPACITY REPLACEMENT COST (CRC/$)
B74: (F0) [W9] @IF(B9=2#AND#B71<250,1004*(-478+26.8*(B67)+2.71*B71),0)
B75: [W9] \-
A76: [W53] '    ACTUAL CAPACITY REPLACEMENT COST (CRC/$)
B76: [W9] @SUM(B73..B74)
A77: [W53] \-
B77: [W9] \-
```

TABLE B-2. CONTINUED

```
A78: [W53] 'V.  CALCULATE COSTS (CC)
B78: (F0) [W9] @IF(B6=1#AND#B8=1,B80,@IF(B6=1#AND#B8=2,B81,@IF(B6=2#AND#B8=1,D80,@IF(B6=2#AND#B8=2,D81,@IF(B6=3#AND#B8=1,B82,@IF(B6=3#AND#B8=2,B82,0))))))
A80: [W53] '    CONTROL TYPE=1/SYSTEM TYPE=1
B80: (F0) [W9] @IF(B6=1#AND#B8=1,5140*(B3^0.34),0)
A81: [W53] '    CONTROL TYPE=1/SYSTEM TYPE=2
B81: (F0) [W9] @IF(B6=1#AND#B8=2,6150*(B3^0.34),0)
C80: [W53] '    CONTROL TYPE=2/SYSTEM TYPE=1
D80: (F0) [W9] @IF(B6=2#AND#B8=1,14600*D31*B3^0.16,0)
C81: [W53] '    CONTROL TYPE=2/SYSTEM TYPE=2
D81: (F0) [W9] @IF(B6=2#AND#B8=2,24000*D31*B3^0.16,0)
A82: [W53] '    CONTROL TYPE=3/SYSTEM TYPE=1 75<=Q<250
B82: (F0) [W9] @IF(B6=3#AND#B8=1#AND#B3>=75#AND#B3<250,(13900*((B3/B31)^0.25)*B31)+B73,0)
A83: [W53] '    CONTROL TYPE=3/SYSTEM TYPE=2 75<=Q<250
B83: (F0) [W9] @IF(B6=3#AND#B8=2#AND#B3>=75#AND#B3<250,(21200*((B3/B31)^0.25)*B31)+B76,0)
A84: [W53] '    CONTROL TYPE=3/SYSTEM TYPE=1 AND NOT 75<=Q<250
B84: (F0) [W9] @IF(B6=3#AND#B8=1#AND#B3<75#AND#B3>=250,(13900*((B3/B31)^0.25)*B31),0)
A85: [W53] '    CONTROL TYPE=3/SYSTEM TYPE=2 AND NOT 75<=Q<250
B85: (F0) [W9] @IF(B6=3#AND#B8=2#AND#B3<75#AND#B3>=250,(21200*((B3/B31)^0.25)*B31),0)
A87: [W53] 'CAPITAL COST
B87: (F0) [W9] +B80+B81+D80+D81+B82+B83+B84+B85
A88: [W53] \-
A89: [W53] 'VI. ANNUALIZED COSTS
A91: [W53] '     INPUT INTEREST RATE (%)
B91: (F0) [W9] @IF(B11=0,10,B11)
A92: [W53] '     INPUT SERVICE LIFE (# YEARS)
B92: (F0) [W9] @IF(B12=0,15,B12)
A93: [W53] '
A94: [W53] '     CAPITAL RECOVERY FACTOR (CRF)
B94: (F4) [W9] (B91/100)*((1+B91/100)^B92)/(((1+B91/100)^B92)-1)
A96: [W53] '     ANNUAL COST (AC)
B96: (F0) [W9] @IF(B6=1#OR#B3>250#OR#B3<75#OR#B71>=30,(B94+0.04)*B87,((B94+0.04)*B87)+26500*B71)
A98: [W53] \-
A99: [W53] 'VII. COST EFFECTIVENESS
A101: [W53] '     CAPACITY FACTOR
B101: (F2) [W9] @IF(B4=0,0.5,B4)
A102: [W53] '     CONTROLLED NOx LEVEL
B102: (F3) [W9] @IF(B6=3#AND#B3>=75#AND#B3<250#AND#B9=1,B56,B25)
A103: [W53] '     COST EFFECTIVENESS (CE) ($/TON NOX REMOVED)
B103: (F0) [W9] +B96/(B101*8760*B3*(0.25-B25)/2000)
```

TABLE B-3. RESIDUAL OIL MODEL LISTING

```
A1: [W53] 'INPUT DATA FOR RESIDUAL OIL
A3: [W53] 'Boiler Size (MMBtu/hr) -
B3: [W9] 225
A4: [W53] 'Capacity Factor (Value or 0=Default)
B4: [W9] 0
A5: [W53] 'Fuel Type (1=Coal, 2=RO, 3=NG/DO)
B5: [W9] 2
A6: [W53] 'Control Type (1=LEA,2=OFA)
B6: [W9] 2
A7: [W53] 'Number of Burners (0=Default or Number)
B7: [W9] 0
A8: [W53] 'Number of Overfire Air Ports (0=Default or Number)
B8: [W9] 1
A9: [W53] 'System Type (1=New 2=Retrofit)
B9: [W9] 2
A10: [W53] 'Capacity Replacement (1=Yes, 2=No)
B10: [W9] 1
A11: [W53] '  For 75>=Q<250
A12: [W53] 'Interest Rate (Percent or 0=Default)
B12: [W9] 10
A13: [W53] 'Service Life (Number of Years or 0=Default)
B13: [W9] 15
A15: [W53] \*
B15: [W9] \*
A16: [W53] 'LOW NOX COSTS FOR RESIDUAL OILS
A17: [W53] \*
B17: [W9] \*
A19: [W53] 'DEFAULT VALUES
A20: [W53] \=
B20: [W9] \=
A21: [W53] 'PERCENT NOX REDUCTION
B21: [W9] @IF(B6=1,15,@IF(B6=2,30,0))
A22: [W53] 'CONTROLLED NOX EMISSIONS
B22: [W9] +B23*(100-B21)/100
A23: [W53] 'UNCONTROLLED NOX EMISSIONS
B23: [W9] @IF(B5=2,0.45,0)
A25: [W53] 'OVERFIRE AIR PORTS (OFA)
B25: [W9] @IF(B8=0,@IF(B3>=10#AND#B3<250,1,@IF(B3>=250#AND#B3<500,2,@IF(B3>=500#AND#B3<750,3,@IF(B3>=750#AND#B3<1300,4,0)))),B8)
```

TABLE B-3. CONTINUED

```
A27: [W53] 'PERCENT DERATE (PD)
B27: [W9] @IF(B3>=75#AND#B3<100,15,@IF(B3>=100#AND#B3<150,20,@IF(B3>=150#AND#B3<200,30,@IF(B3>=200#AND#B3<250,40,0))))
A29: [W53] 'DERATED BOILER CAPACITY (QD)
B29: [W9] +B3/(1-(B27/100))
A31: [W53] 'INTEREST RATE
B31: [W9] @IF(B12=0,10,B12)
A32: [W53] 'SERVICE LIFE
B32: [W9] @IF(B13=0,15,B13)
A34: [W53] 'CAPACITY FACTOR
B34: [W9] @IF(B4=0,0.55,B4)
A36: [W53] 'ADDITIONAL CAPACITY REQUIRED
A37: [W53] 'DUE TO DERATING (QA)
A38: [W53] \=
A39: [W53] 'NEW SYSTEM
B39: (F0) [W9] @IF(B9=1,B29,B38)
A40: [W53] 'RETROFIT SYSTEM
B40: (F0) [W9] @IF(B9=2,B29-B3,0)
B41: (F0) [W9] \=
B42: (F0) [W9] @SUM(B39..B40)
A46: [W53] 'CAPACITY REPLACEMENT COST (CRC)
A47: [W53] \=
A48: [W53] 'SIZE >= 250
B48: (F0) [W9] @IF(B42>=250,1004*(8+59.47*(B27))+7.52*B42,1004*(-478+26.8*B27+2.71*B42))
A53: [W53] 'CAPITAL COSTS
A54: [W53] \=
A55: [W53] 'LEA
B55: (F0) [W9] @IF(B6=1#AND#B9=1,5140*B3^0.34,@IF(B6=1#AND#B9=2,6150*B3^0.34,0))
A56: [W53] 'OFA
B56: (F0) [W9] @IF(B6=2#AND#B9=1,(14600*(B3^0.16)*B25)+B48,@IF(B6=2#AND#B9=2,(24000*(B3^0.16)*B25)+B48,0))
B57: (F0) [W9] \=
B58: (F0) [W9] @SUM(B55..B56)
A60: [W53] 'ANNUALIZED COST
A61: [W53] \=
A62: [W53] 'CAPITAL RECOVERY FACTOR (CRF)
B62: (F4) [W9] (B12/100)*((1+B12/100)^B13)/(((1+B12/100)^B13)-1)
A64: [W53] 'ANNUALIZED COST
B64: (F0) [W9] @IF(B6=1#OR#B3<75#OR#B3>250#OR#B42>=30,(B62+0.04)*B58,@IF(B3>=75#AND#B3<=250#AND#B42<30,(B62+0.04)*B58+26500*B42,0))
A66: [W53] 'COST EFFECTIVENESS
B66: (F0) [W9] +B64/(B34*8760*B3*(B23-B22)/2000)
```